(4)

Greenhagen, Andrew

From:	McDonald, Scott <Scott.McDonald@adm.com>
Sent:	Thursday, September 04, 2014 5:50 PM
To:	Greenhagen, Andrew
Cc:	Rzeznik, Dana; Bayer, MaryRose; Frommelt, Dean
Subject:	Financial Responsibility Cost Estimate
Attachments:	Financial Responsibility - Patrick Engineering Reference Report.pdf; Financial Responsibility Cost Estimate - CCS#1.pdf
Importance:	High

Take a look at the attached documents and let me know if they are acceptable. If so I will start moving on developing the balance of the FR documentation.

Best Regards,

Scott MCDONALD
Biofuels Development Director
Project Director, IL-ICCS Project
Archer Daniels Midland Company
1001 N. Brush College Rd.
Decatur, IL 62521
217-451-5142: Direct
217-451-2457: Fax
217-358-2437: Cell
scott.mcdonald@adm.com

From: Greenhagen, Andrew [mailto:Greenhagen.Andrew@epa.gov]
Sent: Thursday, September 04, 2014 3:24 PM
To: McDonald, Scott
Subject: RE: IBDP Permit for CCS#1 - Attachment G

Hi Scott,

Yes, our basic assumption for CCS1 FR was that you would draw from the CCS2 documents and largely follow the same format.

Thanks,
Andrew

Andrew Greenhagen
Underground Injection Control Branch
U.S. EPA - Region 5
(312) 353-7648

From: McDonald, Scott [mailto:Scott.McDonald@adm.com]
Sent: Thursday, September 04, 2014 2:48 PM
To: Greenhagen, Andrew
Subject: RE: IBDP Permit for CCS#1 - Attachment G
Importance: High

OK we are checking into the perforation depths and will insure the text and the drawings are consistent.

I have one question. Can ADM prepare the FR cost estimate using or citing the figures in the CCS#2 cost estimate prepared by Patrick Engineering? This will save significant time versus ADM contracting Patrick Engineering to develop the cost estimate. I would include the original Patrick Engineering Report as an attachment to the FR.

Best Regards,

Scott MCDONALD
Biofuels Development Director
Project Director, IL-ICCS Project
Archer Daniels Midland Company
1001 N. Brush College Rd.
Decatur, IL 62521
217-451-5142: Direct
217-451-2457: Fax
217-358-2437: Cell
scott.mcdonald@adm.com

From: Greenhagen, Andrew [mailto:Greenhagen.Andrew@epa.gov]
Sent: Thursday, September 04, 2014 1:47 PM
To: McDonald, Scott
Subject: RE: IBDP Permit for CCS#1 - Attachment G

Hi Scott,

Thanks for sending these. Is it possible for you to more clearly show/label the 80 feet of cement at the bottom of the well on the schematics? We both know it is there, but to make it abundantly clear to the public, I think it would be helpful.

Also, in the text on page 5 it says there are perfs from 6976-6978 and 6982-7050. This doesn't match up with the perfs noted on the schematics which list 6976-6978, 6982-7012, and 7025-7050. It would be great if these were all consistent.

Thanks,
Andrew

Andrew Greenhagen
Underground Injection Control Branch
U.S. EPA - Region 5
(312) 353-7648

4

Cost Estimate to Demonstrate Financial Responsibility for Class VI UIC Permit

Archer Daniels Midland Company
Decatur, Illinois

September 4, 2014

Prepared by:

ADM

I. Introduction

The U.S. Environmental Protection Agency (USEPA) has published federal regulations for Underground Injection Control (UIC) Class VI wells that inject carbon dioxide for the purpose of geologic sequestration. These regulations require that owners/operators of Class VI injection wells must demonstrate and maintain financial responsibility for taking corrective action on wells in the Area of Review (AoR), plugging the injection wells once injection ceases, undertaking post-injection site care (PISC) and site closure, and conducting any necessary emergency and remedial response actions to ensure that owners/operators have the resources to allow a third party to carry out any activities that may be needed to protect Underground Sources of Drinking Water (USDW) as required by the regulation.

II. Company qualifications for reference report

Patrick Engineering Inc. is a nationwide engineering, design, and project management firm with a long history of success on a variety of complex infrastructure projects. Their client list includes key government agencies, private and public utilities, and FORTUNE 500 companies in a broad range of industries. They provide pre-construction services, procurement, and construction management of heavy civil infrastructure projects. Patrick has technical experts in the fields of civil, structural, hydraulic, environmental, geotechnical, and electrical engineering, geology, surveying, construction management, process control, and geographic information systems. Engineering News Record (ENR) has included Patrick in its ENR Top 500 for 18 consecutive years and the company has been ranked as one of the Midwest's Top 10 Design Firms for the past five years. Patrick has previously developed financial responsibility cost estimates for Class VI injection wells operators.

III. Project Description

The goal of the IL-ICCS injection project is to demonstrate the ability of the Mt. Simon Sandstone to accept and retain industrial-scale volumes of carbon dioxide (CO_2) for permanent geologic sequestration. The source of the CO_2 is from the fuel ethanol production unit; where high purity biogenic CO_2 is produced during the anaerobic fermentation of sugars to alcohol. The Mt. Simon is the deepest sedimentary rock that overlies the Precambrian-age basement granites of the Illinois Basin and is considered a major regional saline-water bearing reservoir in the Illinois Basin. The project will have an average annual injection rate of between 2,000 metric tonnes per day (MT/day) and 3,000 MT/day; approximately 730,000 to 1.1 million MT annually. The project has an initial projected operational period of five years, in which 4.75 million MTs of CO_2 will be sequestered. Following the operational period, the Operator proposes a post-injection monitoring and site closure period of ten (10) years.

The sequestration site consists of one injection well (herein referred to as Carbon Capture and Sequestration well #1, or CCS #1) with associated equipment, and two wells (one verification well and one geophysical well) for monitoring of the sequestered CO_2. Four shallow monitoring wells are installed in the quaternary strata the most common underground source of drinking water (USDW).

IV. Description of activities considered to demonstrate financial responsibility

In estimating the costs to demonstrate financial responsibility for the geologic sequestration of carbon dioxide at the IBDP site, ADM used the March 13, 2014 report developed by

Patrick Engineering that considers the costs associated with: 1) corrective action on wells, 2) plugging of the injection well and the monitoring wells, 3) post-injection site care, 4) site closure, and 5) emergency and remedial response, as detailed below:

1. Corrective action on wells in the AoR
    a. Review existing plume model
    b. Remodel plume
    c. Perform remedial cementing of defective wells
2. Injection wells and monitoring wells plugging and site reclamation
    a. Injection wells plugging
        i. Casing evaluation
        ii. Cement materials used to plug the well
        iii. Labor, engineering, rig time, equipment
    b. Land reclamation
        i. Removal of gravel well pads and land restoration at injection well #1
3. Post-injection site care
    a. Monitoring wells for geochemical and geophysical analyses
        i. Shallow USDW monitoring wells
        ii. Injection zone monitoring wells
        iii. Above zone monitoring wells
    b. Geophysical surveys
    c. Injection well mechanical integrity testing
    d. Site management and EPA reporting
4. Site closure
    a. Non-endangerment demonstration
    b. Injection zone monitoring wells plugging
        i. Casing evaluation
        ii. Cost for cementing or other materials used to plug the well
        iii. Cost for labor, engineering, rig time, equipment and consultants
        iv. Gravel pad removal
    c. Above confining zone monitoring well and USDW wells plugging
        i. Casing evaluation
        ii. Evaluation of any problems discovered by the casing evaluation
        iii. Cost for repairing problems & cleanup of any groundwater or soil contamiation
        iv. Cost for cementing or other materials used to plug the well
        v. Cost for labor, engineering, rig time, equipment and consultants
        vi. Gravel pad removal
    d. Land reclamation
    e. Document plugging and closure process
5. Emergency and remedial response
    a. Post-injection USDW contamination
        i. Acidification due to migration of CO_2
        ii. Toxic metal dissolution and mobilization
        iii. Displacement of groundwater with brine due to CO_2 injection
    b. Post-Injection Failure Scenarios (acute)
        i. Upward leakage through CO_2 injection well
        ii. Upward leakage through deep oil and gas wells
        iii. Upward leakage through undocumented, abandoned, or substandard wells
    c. Post-injection failure scenarios (chronic)
        i. Upward leakage through caprock through gradual failure
        ii. Release through existing faults due to effects of increased pressure
        iii. Release through induced faults due to effects of increased pressure
        iv. Upward leakage through CO_2 injection well
        v. Upward leakage through deep oil and gas wells

vi. Upward leakage through undocumented, abandoned, or substandard deep wells

d. Other

i. Catastrophic failure of caprock

ii. Failure of caprock/seals or well integrity due to seismic event

V. Basis used to develop cost estimates

ADM contracted Patrick Engineering to provide a third-party cost estimate to meet the required financial responsibility activities: corrective action on wells in the AoR; injection well plugging; post-injection site care and site closure; and emergency and remedial response. Patrick used the EPA's UIC Program Class VI Financial Responsibility Guidance[1] as the basis to define the activities required to be included in the cost estimate. The costs of the required activities were then estimated from:

1) historic price data from other projects the company has managed,
2) cost quotes from third-party companies,
3) EPA's Geologic CO_2 Sequestration Technology and Cost Analysis document[2], and
4) professional judgment on the level of effort required to complete an activity.

The estimated costs are in current (2014) dollars and reflect the costs of a third party to complete the work. The unit costs are fully loaded with general and administrative costs; overhead and profit are also included.

In developing the estimate, Patrick assumed the costs would be incurred if ADM was no longer involved in the project and a third party was asked to conclude the project in a manner to protect USDWs. Thus, the costs included in this estimate would cover the efforts required to ensure the protection of USDWs at no cost to the public. The cost estimate assumes that the third party would not take over and complete the injection project and that CO_2 injection would cease immediately.

VI. Area of Review and Corrective Action Cost Estimate

The estimated costs in this section cover the periodic reevaluation of the AoR and the identification and remediation of newly identified deficient wells. The initial AoR was defined as a circle with a 2.0 mile radius from the injection well. The radius of the AoR was determined using modeling methods as detailed in Section 5 of the Class VI injection well permit application. This area was assumed to be large enough to contain any projected CO_2 plume and pressure effects that might be projected from computational modeling. After modeling is completed, all deficient wells found in the initial AoR would be remediated before injection begins. Therefore, no cost is included to remediate deficient wells within the initial AoR.

As noted above, this cost estimate assumes CO_2 injection would cease at, or would have ceased by, the time a third party was needed to take over responsibility for the injection well and storage site. For purposes of the cost estimate, a reevaluation of the AoR would occur at the time a third party took responsibility and then would occur once every five years during the 50-

[1] *Underground Injection Control (UIC) Class VI Program. Financial Responsibility Guidance.* USEPA Office of Water (4606-M). EPA 816-D-10-010, July 2011.

[2] *Geologic CO2 Sequestration Technology and Cost Analysis.* USEPA Office of Water (4606-M). EPA 816-D-10-008, November 2010.

year post-injection period – the minimum frequency required by the Class VI regulations (this cost estimate assumes that the applicable regulatory agencies have approved the shorter PISC period of 10 years that was requested by ADM). Should the injection reservoir tracking data obtained over the five-year period deviate significantly from the predictions of the original (or updated) computational model, the model would be updated to reflect the actual measured shape and extent of the CO_2 plume and improve the accuracy of the predicted AoR. It is assumed this would only be necessary once during the post-injection period as the model would have been regularly verified and updated during the injection period.

Any newly identified wells are assumed to be either deficient wells within the initial AoR which were not discovered before injection, or deficient wells added because of adjustments to the AoR due to ongoing monitoring of the plume during injection. With the exception of the Illinois Basin Decatur Project (IBDP) verification well and the Illinois Industrial Carbon Capture and Storage Project (IL-ICCS) injection well and verification well (VW #1, CCS#2, and VW #2), there are no wells within in the AoR (or within several miles of the AoR) that penetrate the confining layer (the Eau Claire formation). For this reason, ADM believes that the likelihood of encountering additional wells within an adjusted AoR is negligible. No corrective actions are expected to be necessary within the AoR.

Table 1: Corrective Action on Wells in Area of Review

Activity	Unit			Unit Cost ($)			Total Costs ($)
a. Review existing plume model (at 5 years and at 10 years post-injection)	1250	hrs	@	160	per hour	=	200,000
b. Review of state databases of known wells and abandoned mines (every five years)	12	hrs	@	150	per hour	=	1,800
c. Project management and oversight	200	hrs	@	150	per hour	=	30,000
Total Corrective Action on Wells in AoR over 10-year Post-injection Period							**231,800**

VII. Injection Well Plugging and Site Reclamation Cost Estimate

The estimated costs in this section cover the plugging of the injection well after injection had ceased. Site reclamation for the plugged sites is included in the cost as well.

The costs are broken into two areas: 1) plugging and abandoning the injection well, 2) land reclamation including removal of injection site buildings and appurtenances. The costs are one-time costs that would be paid at the end of the PISC period as the injection well will be used during this period to monitor the pressure of the formation and conduct geophysical surveys.

The plugging of the well would include mechanical integrity testing, plugging the hole with cement for the entire depth of the well, and cutting the well off below the ground. All structures and appurtenances at the site of the injection well would be removed except for those directly necessary to the continued monitoring of the plume. The surface facilities remaining for post-injection monitoring would be removed during site closure.

Well plugging and site remediation costs were estimated based on costs incurred or estimated for other projects as well as cost estimates obtained by ADM for plugging CCS #2.

Table 2: Injection Wells & Monitoring Wells Plugging & Site Reclamation Summary

Activity	Total Cost ($)
a. Injection wells plugging	582,200
b. Land reclamation	11,920
Total Injection Wells & Site Reclamation	**594,120**

Table 2a: Injection Well Plugging & Site Reclamation Detail

Activity	Unit			Unit Cost ($)			Total Costs ($)
a. Injection wells plugging							
i. Casing evaluation	1	Well	@	35,000	per well	=	35,000
ii. Repair problem & groundwater cleanup	1	Well	@	0	per well	=	0
iii. Cement materials used to plug the well	1	Well	@	116,500	per well	=	116,500
iv. Labor, engineering, rig time, equipment	1	Well	@	363,500	per well	=	363,500
Miscellaneous and minor contingencies (10%)	1	Well	@	48,000	per well	=	48,000
Project Management and Oversight (120 hours @ $160/hour)							19,200
Total injection wells plugging							**582,200**
b. Land reclamation							
i. Removal of gravel well pads and land restoration at injection well	1	pad	@	10,000	per pad	=	10,000
Project Management and Oversight (12 hours @ $160/hour)							1,920
Total land reclamation							**11,920**
Total Injection Wells & Site Reclamation Cost							**594,120**

VIII. Post-Injection Site Care Cost Estimate

The estimated costs in this section cover the tracking and modeling of the plume during the 10-year post-injection period.

The PISC activities would include collecting geochemical and geophysical monitoring data from the injection well, one in-zone monitoring well (VW #2), and one above-zone monitoring well (GM #2). Groundwater samples will also be collected from the four installed shallow monitoring wells and the deep monitoring wells (VW #1 and #2 and GM #2). The data collected would include continuous formation temperature and pressure readings and annual sampling. Additionally, reservoir saturation tool (RST) surveys will be conducted during PISC years 1, 3, 5, 7, and 10 and seismic surveys will be conducted at PISC year 1, and at the end of the 10 year PISC period. The data from these RST surveys, along with the deep well geochemical and geophysical data, would be used to verify and, if necessary, recalibrate the computational model. PISC costs would also include record keeping and reporting the information to the proper governmental agency. The shallow monitoring well sampling would occur annually throughout the PISC period.

The PISC costs were estimated based on costs incurred or estimated for other projects, quotes submitted to ADM, and EPA guidance[3].

Table 3: Post-injection Site Care Summary

Activity	Total Cost ($)
a. Monitoring wells for geochemical and geophysical analyses	2,334,500
b. Geophysical surveys	3,720,000
c. Monitoring well mechanical integrity testing	380,000
d. ADM Site management and EPA reporting	1,950,000
Total post-injection site care	**8,384,500**

Table 3a: Post-injection Site Care Detail

a. Monitoring wells for geochemical and geophysical analyses				
Activity	**Number of Wells**	**Base Cost ($)**	**Unit Cost ($)**	**Annual Cost ($)**
Shallow well USDW monitoring (7 samples, years 1-10)	7	20,000 (twice)	1,750	12,250
Deep well groundwater monitoring (years 1-10)	5	15,000 (twice)	54,200 per event	54,200
Injection zone monitoring well VW #2 (pressure, temperature)	1	-	20,000	20,000
Injection well CCS #2 (annulus pressure, formation pressure)	1	-	50,000	50,000
Above zone monitoring well GM #2 (pressure, temperature)	1	-	20,000	20,000
Project management and oversight (438 hours @ $160/hour)				70,000
Annual well monitoring cost				226,450
Total well monitoring cost for 10 years post-injection				**2,334,500**
b. Geophysical Surveys				
Activity	**Base Cost ($)**	**Number of Wells**	**Unit Cost ($)**	**Total Costs ($)**
RST survey (years 1, 3, 5, 7, 10)	-	4	26,000	520,000
Surface 3D (4D) survey (years 1 and 10)	100,000	2 sq. mi.	750,000	3,200,000
Total Geophysical Surveys over 10 years				**3,720,000**

[3] *Ibid.*

Table 3a (continued)

c. Injection well mechanical integrity testing				
Activity	**Number of Wells**	**Base Cost ($)**	**Unit Cost**	**Annualized Cost ($)**
Injection well (annually)	1	35,000	-	35,000
Project management and oversight (100 hours @ $150/hour every five years)				3,000
Annualized monitoring well operation and maintenance				38,000
Total monitoring well operation and maintenance for 10 years post-injection				**380,000**

d. ADM Site management and EPA reporting					
Activity	**Annual hours**		**Unit Cost ($)**		**Total Costs ($)**
Record keeping and reporting	438	@	160	per hour	70,000
Project management and oversight	782	@	160	per hour	125,000
Annual site management and EPA reporting					195,000
Total site management and EPA reporting over 10 years					**1,950,000**

IX. Site Closure Cost Estimate

The estimated costs in this section cover the final closure of the site. After the 10-year, post-injection and site care period, and when it could be demonstrated that the project would no longer pose a risk of endangerment to any USDWs, the site would be permanently closed.

The costs are broken into four functional areas; 1) preparing the non-endangerment report, 2) plugging and abandoning all monitoring wells, 2) reclaiming land including removal of remaining surface site buildings and appurtenances, and 3) documenting the site closure process. The costs would be one-time costs that would be paid at the final project termination.

The plugging of the monitoring wells would include mechanical integrity testing, plugging the hole with cement the entire depth of the well, and cutting the well off below the ground. All structures and appurtenances at the sites of the monitoring wells would be completely removed and the sites would be restored to pre-project condition.

Well plugging and site remediation costs were estimated based on costs incurred or estimated for other projects, and cost estimates obtained by ADM.

Table 4: Site Closure Summary

Activity	Total Cost ($)
a. Non-endangerment demonstration	25,000
b. Injection-zone monitoring wells plugging	424,750
c. Above-zone monitoring well plugging	56,350
d. Remove surface features and reclaim land	10,000
e. Document plugging and closure process	19,200
Total site closure	**535,300**

Table 4a: Site Closure Detail

a. Non-endangerment demonstration			
Activity	**Cost per Well ($)**	**Number of Wells**	**Total Cost ($)**
Prepare non-endangerment demonstration report			25,000
Total cost non-endangerment demonstration			**25,000**

b. Injection zone monitoring wells plugging			
Activity	**Cost per Well ($)**	**Number of Wells**	**Total Cost ($)**
Casing evaluation	35,000	1	35,000
Cost for cementing or other materials used to plug the well	49,250	1	49,250
Cost for labor, engineering, rig time, equipment and consultants	314,500	1	314,500
Gravel pad removal	10,000	1	10,000
Project management and oversight (100 hours @ $160/hour)			16,000
Total injection zone monitoring wells plugging			**424,750**

c. Above confining zone monitoring well plugging			
Activity	**Cost per Well ($)**	**Number of Wells**	**Total Cost ($)**
Cost for cementing or other materials used to plug the well	10,650	1	10,650
Cost for labor, engineering, rig time, equipment and consultants	12,500	1	12,500
Gravel pad removal	10,000	1	10,000
Costs for plugging USDW monitoring wells	5,000	4	20,000
Project management and oversight (20 hours @ $160/hour)			3,200
Total cost plug above confining zone monitoring wells			**56,350**

d. Land reclamation			
Activity	**Unit Cost ($)**	**Number**	**Total Cost ($)**
Miscellaneous site restoration activities	10,000	1	10,000
Total land reclamation			**10,000**

e. Documentation			
Activity	**Hours**	**Rate ($/hr)**	**Total Cost ($)**
Document plugging and closure process (well plugging, post-injection plans, notification of intent to close, and post-closure report).	120	160	19,200

Total documentation	**19,200**

X. Emergency and Remedial Response Cost Estimate

It was assumed the response to discovered CO_2 leaks, both acute/high volume and chronic/low volume, would be to plug leaks where possible, assess any impact to USDWs, and remediate any contamination of USDWs. Potential consequences and response actions were taken from Esposito 2010[4]. The cost estimate assumes a maximum affected area of about 2 square miles. The costs include installation and sampling of 6 monitoring wells, installation and operation of 4 extraction wells, extraction, treatment of 10 to 20 gallons per minute of groundwater for 2 years using absorption, and removal of system. The extent and costs of treatment were adapted from Federal Remediation Technologies Roundtable website[5]. The cost of study and well installation were derived from previous experience. Costs for municipal water hook-up are not included as this scenario is deemed to be extremely unlikely, although the cost of remediation may make municipal water hook-up preferable. Also note that treatment costs can vary significantly depending on specific metal and concentration.

The costs of responding to catastrophic events assumed wide areas with groundwater impacted from CO_2 seeps which would require groundwater remediation and providing alternative water supplies to affected residents.

Table 5: Emergency and Remedial Response Events

Event	Consequences	Response Actions
1. Post-injection USDW contamination		
Acidification due to migration of CO_2	Decrease in pH by 1 to 2 units, mobilization of trace and alkali metals, other geochemical changes to groundwater that result in USDW exceeding applicable standards	Hydrogeological study to delineate 3-D extent and nature of impact to USDW. Groundwater extraction with treatment of groundwater or extraction coupled with injection of 'clean' water, if possible. Significant impact to USDW could require supplying municipal water to affected properties.
Toxic metal dissolution and mobilization	Concentrations of toxic metals in USDW greater than applicable standards	Hydrogeological study to delineate 3-D extent and nature of impact to USDW. Groundwater extraction with treatment of groundwater or extraction coupled with injection of 'clean' water, if possible. Significant impact to USDW could require supplying municipal water to affected properties.

[4] Esposito, Ariel M.M. '*Remediation of Possible Leakage from Geologic CO_2 Storage Reservoirs into Groundwater Aquifers*. Stanford University Department of Energy Resources Engineering. June 2010.

[5] Environmental Cost Estimating Tools. In *Federal Remediation Technologies Roundtable*. Retrieved June 9, 2011. From www.frtr.gov.

Table 5 (continued)

Displacement of groundwater with brine due to CO_2 injection	Concentrations of anions/cations in USDW greater than applicable drinking water standards.	Hydrogeological study to delineate 3-D extent and nature of impact to USDW. Groundwater extraction with treatment of groundwater or extraction coupled with injection of 'clean' water, if possible. Significant impact to USDW could require supplying municipal water to affected properties.
<u>2. Post-injection failure scenarios (acute)</u>		
Upward leakage through CO_2 injection well	Groundwater contamination	1) Stop injection, 2) Pull and replace the tubing or the packer, 3) Repair the well by plugging it with cement, 4) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 5) Install chemical sealant barrier to block leaks, and 6) Remediate groundwater (see 1. above).
Upward leakage through deep oil and gas wells	Groundwater contamination	1) Stop injection, 2) Pull and replace the tubing or the packer, 3) Repair the well by plugging it with cement, 4) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 5) Install chemical sealant barrier to block leaks, and 6) Remediate groundwater (see 1. above).
Upward leakage through undocumented, abandoned, or poorly constructed wells	Groundwater contamination	1) Stop injection, 2) Pull and replace the tubing or the packer, 3) Repair the well by plugging it with cement, 4) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 5) Install chemical sealant barrier to block leaks, and 6) Remediate groundwater (see 1. above).
<u>3. Post-injection failure scenarios (chronic)</u>		
Upward leakage through caprock through gradual failure	Groundwater contamination	Stop injection. Remediate groundwater (see 1. above)
Release through existing faults due to effects of increased pressure	Groundwater contamination	Stop injection. Remediate groundwater (see 1. above)
Release through induced faults due to effects of increased pressure	Groundwater contamination	Stop injection. Remediate groundwater (see 1. above)

Table 5 (continued)

Upward leakage through CO_2 injection well	Groundwater contamination	1) Stop injection, 2) Repair the well by plugging it with cement, 3) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 4) Install chemical sealant barrier to block leaks, and 5) Remediate groundwater (see 1. above)
Upward leakage through deep oil and gas wells	Groundwater contamination	1) Stop injection, 2) Pull and replace the tubing or the packer, 3) Repair the well by plugging it with cement, 4) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 5) Install chemical sealant barrier to block leaks, and 6) Remediate groundwater (see 1. above).
Upward leakage through undocumented, abandoned, or poorly constructed deep wells	Groundwater contamination	1) Stop injection, 2) Pull and replace the tubing or the packer, 3) Repair the well by plugging it with cement, 4) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 5) Install chemical sealant barrier to block leaks, and 6) Remediate groundwater (see 1. above).
4. Other		
Catastrophic failure of caprock	Groundwater contamination	Stop injection. Remediate groundwater (see 1. above)
Failure of caprock or well integrity due to seismic event	Groundwater contamination	Stop injection. Remediate groundwater (see 1. above)

Table 5a: Emergency and Remedial Response Estimated Costs

Event	Estimated Cost ($)
1. Post-injection USDW contamination	
Acidification due to migration of CO_2	250,000
Toxic metal dissolution and mobilization	3,500,000
Displacement of groundwater with brine due to CO_2 injection	264,500
2. Post-injection failure scenarios (acute)	
Upward leakage through CO_2 injection well	3,277,500
Upward leakage through deep oil and gas wells	2,070,000
Upward leakage through undocumented, abandoned, or poorly constructed wells	2,070,000
3. Post-injection failure scenarios (chronic)	
Upward leakage through caprock through gradual failure	3,500,000
Release through existing faults due to effects of increased pressure	3,500,000
Release through induced faults due to effects of increased pressure	3,750,000
Upward leakage through CO_2 injection well	805,000
Upward leakage through deep oil and gas wells	402,500
Upward leakage through undocumented, abandoned, or poorly constructed deep wells	402,500
4. Other	
Catastrophic failure of caprock	3,500,000
Failure of caprock/seals or well integrity due to seismic event	3,500,000
Total Emergency and Remedial Response	**30,792,000**

XI. Cost Summary

For the IL-ICCS CO_2 injection site, the total cost for a third party to take corrective actions on wells within the AoR, plug the injection wells, conduct post-injection site care and site closure actions necessary to protect USDWs if ADM were unable to do so is estimated to be $7,795,720 as shown in Table 6. Possible emergency and remedial response actions as necessary to protect USDWs could possibly amount to as much as $3,750,000 for a single event.

Table 6: Total Financial Responsibility Cost by Category

Activity	Total Cost ($)
Corrective action on wells in AoR	231,800
Injection wells & monitoring wells plugging & site reclamation	594,120
Third Party Post-injection site care	6,434,500
Site closure	535,300
Total Financial Responsibility	**7,795,720**

The costs, assuming a 5-year injection period followed by a 10-year PISC period, are shown by category projected over time in Table 7 on the following page

Table 7: Total Financial Responsibility Cost by Category and Year (in 2014 dollars)

Year After Injection Stops	Corrective action on wells in AoR Cost ($)	Injection wells & site reclamation Cost ($)	Post-injection Site Care Cost ($)	Site Closure Cost ($)	Annualized Emergency/ Remedial Response (single event, $)
1	239,800	-	703,800	-	375,000
2	-	-	786,050	-	375,000
3	-	-	408,800	-	375,000
4	-	-	369,600	-	375,000
5	-	-	419,600	-	375,000
6	1,800	-	369,600	-	375,000
7	-	-	369,600	-	375,000
8	-	-	369,600	-	375,000
9	-	-	369,600	-	375,000
10	48,000	594,120	2,019,600	535,300	375,000

COST ESTIMATE TO DEMONSTRATE FINANCIAL RESPONSIBILITY FOR CLASS VI UIC PERMIT

FOR

ARCHER DANIELS MIDLAND COMPANY
DECATUR, ILLINOIS

MARCH 13, 2014

PREPARED BY:

PATRICK ENGINEERING

I. Introduction

The U.S. Environmental Protection Agency (USEPA) has published federal regulations for Underground Injection Control (UIC) Class VI wells that inject carbon dioxide for the purpose of geologic sequestration. These regulations require that owners/operators of Class VI injection wells must demonstrate and maintain financial responsibility for taking corrective action on wells in the Area of Review (AoR), plugging the injection wells once injection ceases, undertaking post-injection site care (PISC) and site closure, and conducting any necessary emergency and remedial response actions to ensure that owners/operators have the resources to allow a third party to carry out any activities that may be needed to protect Underground Sources of Drinking Water (USDW) as required by the regulation.

II. Company qualifications

Patrick Engineering Inc. is a nationwide engineering, design, and project management firm with a long history of success on a variety of complex infrastructure projects. Their client list includes key government agencies, private and public utilities, and FORTUNE 500 companies in a broad range of industries. They provide pre-construction services, procurement, and construction management of heavy civil infrastructure projects. Patrick has technical experts in the fields of civil, structural, hydraulic, environmental, geotechnical, and electrical engineering, geology, surveying, construction management, process control, and geographic information systems. Engineering News Record (ENR) has included Patrick in its ENR Top 500 for 18 consecutive years and the company has been ranked as one of the Midwest's Top 10 Design Firms for the past five years. Patrick has previously developed financial responsibility cost estimates for Class VI injection wells operators.

III. Project Description

The goal of the IL-ICCS injection project is to demonstrate the ability of the Mt. Simon Sandstone to accept and retain industrial-scale volumes of carbon dioxide (CO_2) for permanent geologic sequestration. The source of the CO_2 is from the fuel ethanol production unit; where high purity biogenic CO_2 is produced during the anaerobic fermentation of sugars to alcohol. The Mt. Simon is the deepest sedimentary rock that overlies the Precambrian-age basement granites of the Illinois Basin and is considered a major regional saline-water bearing reservoir in the Illinois Basin. The project will have an average annual injection rate of between 2,000 metric tonnes per day (MT/day) and 3,000 MT/day; approximately 730,000 to 1.1 million MT annually. The project has an initial projected operational period of five years, in which 4.75 million MTs of CO_2 will be sequestered. Following the operational period, the Operator proposes a post-injection monitoring and site closure period of ten (10) years.

The sequestration site consists of one injection well (herein referred to as Carbon Capture and Sequestration well #2, or CCS #2) with associated equipment, and two wells (one verification well and one geophysical well) for monitoring of the sequestered CO_2. Four additional monitoring wells will also be installed in the lowermost underground source of drinking water (USDW).

IV. Description of activities considered to demonstrate financial responsibility

In estimating the costs to demonstrate financial responsibility for the geologic sequestration of carbon dioxide by ADM at the IL-ICCS site, Patrick Engineering has considered the costs associated with: 1) corrective action on wells, 2) plugging of the injection well and the monitoring wells, 3) post-injection site care, 4) site closure, and 5) emergency and remedial response, as detailed below:

1. Corrective action on wells in the AoR
    a. Review existing plume model
    b. Remodel plume
    c. Perform remedial cementing of defective wells
2. Injection wells and monitoring wells plugging and site reclamation
    a. Injection wells plugging
        i. Casing evaluation
        ii. Cement materials used to plug the well
        iii. Labor, engineering, rig time, equipment
    b. Land reclamation
        i. Removal of gravel well pads and land restoration at injection well #1
3. Post-injection site care
    a. Monitoring wells for geochemical and geophysical analyses
        i. Shallow USDW monitoring wells
        ii. Injection zone monitoring wells
        iii. Above zone monitoring wells
    b. Geophysical surveys
    c. Injection well mechanical integrity testing
    d. Site management and EPA reporting
4. Site closure
    a. Non-endangerment demonstration
    b. Injection zone monitoring wells plugging
        i. Casing evaluation
        ii. Cost for cementing or other materials used to plug the well
        iii. Cost for labor, engineering, rig time, equipment and consultants
        iv. Gravel pad removal
    c. Above confining zone monitoring well and USDW wells plugging
        i. Casing evaluation
        ii. Evaluation of any problems discovered by the casing evaluation
        iii. Cost for repairing problems & cleanup of any groundwater or soil contamiation
        iv. Cost for cementing or other materials used to plug the well
        v. Cost for labor, engineering, rig time, equipment and consultants
        vi. Gravel pad removal
    d. Land reclamation
    e. Document plugging and closure process
5. Emergency and remedial response
    a. Post-injection USDW contamination
        i. Acidification due to migration of CO_2
        ii. Toxic metal dissolution and mobilization
        iii. Displacement of groundwater with brine due to CO_2 injection
    b. Post-Injection Failure Scenarios (acute)
        i. Upward leakage through CO_2 injection well
        ii. Upward leakage through deep oil and gas wells
        iii. Upward leakage through undocumented, abandoned, or substandard wells
    c. Post-injection failure scenarios (chronic)
        i. Upward leakage through caprock through gradual failure
        ii. Release through existing faults due to effects of increased pressure
        iii. Release through induced faults due to effects of increased pressure
        iv. Upward leakage through CO_2 injection well
        v. Upward leakage through deep oil and gas wells

   vi. Upward leakage through undocumented, abandoned, or substandard deep wells
d. Other
   i. Catastrophic failure of caprock
   ii. Failure of caprock/seals or well integrity due to seismic event

V. Basis used to develop cost estimates

ADM contracted with Patrick Engineering to provide a third-party cost estimate to meet the required financial responsibility activities: corrective action on wells in the AoR; injection well plugging; post-injection site care and site closure; and emergency and remedial response. Patrick used the EPA's UIC Program Class VI Financial Responsibility Guidance[1] as the basis to define the activities required to be included in the cost estimate. The costs of the required activities were then estimated from:

1) historic price data from other projects the company has managed,
2) cost quotes from third-party companies,
3) EPA's Geologic CO_2 Sequestration Technology and Cost Analysis document[2], and
4) professional judgment on the level of effort required to complete an activity.

The estimated costs are in current (2014) dollars and reflect the costs of a third party to complete the work. The unit costs are fully loaded with general and administrative costs; overhead and profit are also included.

In developing the estimate, Patrick assumed the costs would be incurred if ADM was no longer involved in the project and a third party was asked to conclude the project in a manner to protect USDWs. Thus, the costs included in this estimate would cover the efforts required to ensure the protection of USDWs at no cost to the public. The cost estimate assumes that the third party would not take over and complete the injection project and that CO_2 injection would cease immediately.

VI. Area of Review and Corrective Action Cost Estimate

The estimated costs in this section cover the periodic reevaluation of the AoR and the identification and remediation of newly identified deficient wells. The initial AoR was defined as a circle with a 2.0 mile radius from the injection well. The radius of the AoR was determined using modeling methods as detailed in Section 5 of the Class VI injection well permit application. This area was assumed to be large enough to contain any projected CO_2 plume and pressure effects that might be projected from computational modeling. After modeling is completed, all deficient wells found in the initial AoR would be remediated before injection begins. Therefore, no cost is included to remediate deficient wells within the initial AoR.

As noted above, this cost estimate assumes CO_2 injection would cease at, or would have ceased by, the time a third party was needed to take over responsibility for the injection well and storage site. For purposes of the cost estimate, a reevaluation of the AoR would occur at the time a third party took responsibility and then would occur once every five years during the 50-

---

[1] *Underground Injection Control (UIC) Class VI Program. Financial Responsibility Guidance.* USEPA Office of Water (4606-M). EPA 816-D-10-010, July 2011.

[2] *Geologic CO2 Sequestration Technology and Cost Analysis.* USEPA Office of Water (4606-M). EPA 816-D-10-008, November 2010.

year post-injection period – the minimum frequency required by the Class VI regulations (this cost estimate assumes that the applicable regulatory agencies have approved the shorter PISC period of 10 years that was requested by ADM). Should the injection reservoir tracking data obtained over the five-year period deviate significantly from the predictions of the original (or updated) computational model, the model would be updated to reflect the actual measured shape and extent of the CO_2 plume and improve the accuracy of the predicted AoR. It is assumed this would only be necessary once during the post-injection period as the model would have been regularly verified and updated during the injection period.

Any newly identified wells are assumed to be either deficient wells within the initial AoR which were not discovered before injection, or deficient wells added because of adjustments to the AoR due to ongoing monitoring of the plume during injection. With the exception of the Illinois Basin Decatur Project (IBDP) injection well and verification well (CCS #1 and VW #1), there are no wells within in the AoR (or within several miles of the AoR) that penetrate the confining layer (the Eau Claire formation). For this reason, ADM believes that the likelihood of encountering additional wells within an adjusted AoR is negligible. No corrective actions are expected to be necessary within the AoR.

Table 1: Corrective Action on Wells in Area of Review

Activity	Unit			Unit Cost ($)			Total Costs ($)
a. Review existing plume model (at 5 years and at 10 years post-injection)	1250	hrs	@	160	per hour	=	200,000
b. Review of state databases of known wells and abandoned mines (every five years)	12	hrs	@	150	per hour	=	1,800
c. Project management and oversight	200	hrs	@	150	per hour	=	30,000
Total Corrective Action on Wells in AoR over 10-year Post-injection Period							**231,800**

VII. Injection Well Plugging and Site Reclamation Cost Estimate

The estimated costs in this section cover the plugging of the injection well after injection had ceased. Site reclamation for the plugged sites is included in the cost as well.

The costs are broken into two areas: 1) plugging and abandoning the injection well, 2) land reclamation including removal of injection site buildings and appurtenances. The costs are one-time costs that would be paid at the end of the PISC period as the injection well will be used during this period to monitor the pressure of the formation and conduct geophysical surveys.

The plugging of the well would include mechanical integrity testing, plugging the hole with cement for the entire depth of the well, and cutting the well off below the ground. All structures and appurtenances at the site of the injection well would be removed except for those directly necessary to the continued monitoring of the plume. The surface facilities remaining for post-injection monitoring would be removed during site closure.

Well plugging and site remediation costs were estimated based on costs incurred or estimated for other projects as well as cost estimates obtained by ADM for plugging CCS #2.

Table 2: Injection Wells & Monitoring Wells Plugging & Site Reclamation Summary

Activity	Total Cost ($)
a. Injection wells plugging	582,200
b. Land reclamation	11,920
Total Injection Wells & Site Reclamation	**594,120**

Table 2a: Injection Well Plugging & Site Reclamation Detail

Activity	Unit			Unit Cost ($)			Total Costs ($)
a. Injection wells plugging							
i. Casing evaluation	1	Well	@	35,000	per well	=	35,000
ii. Repair problem & groundwater cleanup	1	Well	@	0	per well	=	0
iii. Cement materials used to plug the well	1	Well	@	116,500	per well	=	116,500
iv. Labor, engineering, rig time, equipment	1	Well	@	363,500	per well	=	363,500
Miscellaneous and minor contingencies (10%)	1	Well	@	48,000	per well	=	48,000
Project Management and Oversight (120 hours @ $160/hour)							19,200
Total injection wells plugging							**582,200**
b. Land reclamation							
i. Removal of gravel well pads and land restoration at injection well	1	pad	@	10,000	per pad	=	10,000
Project Management and Oversight (12 hours @ $160/hour)							1,920
Total land reclamation							**11,920**
Total Injection Wells & Site Reclamation Cost							**594,120**

VIII. Post-Injection Site Care Cost Estimate

The estimated costs in this section cover the tracking and modeling of the plume during the 10-year post-injection period.

The PISC activities would include collecting geochemical and geophysical monitoring data from the injection well, one in-zone monitoring well (VW #2), and one above-zone monitoring well (GM #2). Groundwater samples will also be collected from the four installed shallow monitoring wells and the deep monitoring wells (VW #1 and #2 and GM #2). The data collected would include continuous formation temperature and pressure readings and annual sampling. Additionally, reservoir saturation tool (RST) surveys will be conducted during PISC years 1, 3, 5, 7, and 10 and seismic surveys will be conducted at PISC year 1, and at the end of the 10 year PISC period. The data from these RST surveys, along with the deep well geochemical and geophysical data, would be used to verify and, if necessary, recalibrate the computational model. PISC costs would also include record keeping and reporting the information to the proper governmental agency. The shallow monitoring well sampling would occur annually throughout the PISC period.

The PISC costs were estimated based on costs incurred or estimated for other projects, quotes submitted to ADM, and EPA guidance[3].

Table 3: Post-injection Site Care Summary

Activity	Total Cost ($)
a. Monitoring wells for geochemical and geophysical analyses	2,334,500
b. Geophysical surveys	3,720,000
c. Monitoring well mechanical integrity testing	380,000
d. ADM Site management and EPA reporting	1,950,000
Total post-injection site care	**8,384,500**

Table 3a: Post-injection Site Care Detail

a. Monitoring wells for geochemical and geophysical analyses				
Activity	**Number of Wells**	**Base Cost ($)**	**Unit Cost ($)**	**Annual Cost ($)**
Shallow well USDW monitoring (7 samples, years 1-10)	7	20,000 (twice)	1,750	12,250
Deep well groundwater monitoring (years 1-10)	5	15,000 (twice)	54,200 per event	54,200
Injection zone monitoring well VW #2 (pressure, temperature)	1	-	20,000	20,000
Injection well CCS #2 (annulus pressure, formation pressure)	1	-	50,000	50,000
Above zone monitoring well GM #2 (pressure, temperature)	1	-	20,000	20,000
Project management and oversight (438 hours @ $160/hour)				70,000
			Annual well monitoring cost	226,450
			Total well monitoring cost for 10 years post-injection	**2,334,500**
b. Geophysical Surveys				
Activity	**Base Cost ($)**	**Number of Wells**	**Unit Cost ($)**	**Total Costs ($)**
RST survey (years 1, 3, 5, 7, 10)	-	4	26,000	520,000
Surface 3D (4D) survey (years 1 and 10)	100,000	2 sq. mi.	750,000	3,200,000
			Total Geophysical Surveys over 10 years	**3,720,000**

[3] *Ibid.*

Table 3a (continued)

c. Injection well mechanical integrity testing				
Activity	**Number of Wells**	**Base Cost ($)**	**Unit Cost**	**Annualized Cost ($)**
Injection well (annually)	1	35,000	-	35,000
Project management and oversight (100 hours @ $150/hour every five years)				3,000
Annualized monitoring well operation and maintenance				38,000
Total monitoring well operation and maintenance for 10 years post-injection				**380,000**

d. ADM Site management and EPA reporting					
Activity	**Annual hours**		**Unit Cost ($)**		**Total Costs ($)**
Record keeping and reporting	438	@	160	per hour	70,000
Project management and oversight	782	@	160	per hour	125,000
Annual site management and EPA reporting					195,000
Total site management and EPA reporting over 10 years					**1,950,000**

IX. Site Closure Cost Estimate

The estimated costs in this section cover the final closure of the site. After the 10-year, post-injection and site care period, and when it could be demonstrated that the project would no longer pose a risk of endangerment to any USDWs, the site would be permanently closed.

The costs are broken into four functional areas; 1) preparing the non-endangerment report, 2) plugging and abandoning all monitoring wells, 2) reclaiming land including removal of remaining surface site buildings and appurtenances, and 3) documenting the site closure process. The costs would be one-time costs that would be paid at the final project termination.

The plugging of the monitoring wells would include mechanical integrity testing, plugging the hole with cement the entire depth of the well, and cutting the well off below the ground. All structures and appurtenances at the sites of the monitoring wells would be completely removed and the sites would be restored to pre-project condition.

Well plugging and site remediation costs were estimated based on costs incurred or estimated for other projects, and cost estimates obtained by ADM.

Table 4: Site Closure Summary

Activity	Total Cost ($)
a. Non-endangerment demonstration	25,000
b. Injection-zone monitoring wells plugging	424,750
c. Above-zone monitoring well plugging	56,350
d. Remove surface features and reclaim land	10,000
e. Document plugging and closure process	19,200
Total site closure	**535,300**

Table 4a: Site Closure Detail

a. Non-endangerment demonstration			
Activity	**Cost per Well ($)**	**Number of Wells**	**Total Cost ($)**
Prepare non-endangerment demonstration report			25,000
Total cost non-endangerment demonstration			**25,000**

b. Injection zone monitoring wells plugging			
Activity	**Cost per Well ($)**	**Number of Wells**	**Total Cost ($)**
Casing evaluation	35,000	1	35,000
Cost for cementing or other materials used to plug the well	49,250	1	49,250
Cost for labor, engineering, rig time, equipment and consultants	314,500	1	314,500
Gravel pad removal	10,000	1	10,000
Project management and oversight (100 hours @ $160/hour)			16,000
Total injection zone monitoring wells plugging			**424,750**

c. Above confining zone monitoring well plugging			
Activity	**Cost per Well ($)**	**Number of Wells**	**Total Cost ($)**
Cost for cementing or other materials used to plug the well	10,650	1	10,650
Cost for labor, engineering, rig time, equipment and consultants	12,500	1	12,500
Gravel pad removal	10,000	1	10,000
Costs for plugging USDW monitoring wells	5,000	4	20,000
Project management and oversight (20 hours @ $160/hour)			3,200
Total cost plug above confining zone monitoring wells			**56,350**

d. Land reclamation			
Activity	**Unit Cost ($)**	**Number**	**Total Cost ($)**
Miscellaneous site restoration activities	10,000	1	10,000
Total land reclamation			**10,000**

e. Documentation			
Activity	**Hours**	**Rate ($/hr)**	**Total Cost ($)**
Document plugging and closure process (well plugging, post-injection plans, notification of intent to close, and post-closure report).	120	160	19,200

Total documentation	**19,200**

X. Emergency and Remedial Response Cost Estimate

It was assumed the response to discovered CO_2 leaks, both acute/high volume and chronic/low volume, would be to plug leaks where possible, assess any impact to USDWs, and remediate any contamination of USDWs. Potential consequences and response actions were taken from Esposito 2010[4]. The cost estimate assumes a maximum affected area of about 2 square miles. The costs include installation and sampling of 6 monitoring wells, installation and operation of 4 extraction wells, extraction, treatment of 10 to 20 gallons per minute of groundwater for 2 years using absorption, and removal of system. The extent and costs of treatment were adapted from Federal Remediation Technologies Roundtable website[5]. The cost of study and well installation were derived from previous experience. Costs for municipal water hook-up are not included as this scenario is deemed to be extremely unlikely, although the cost of remediation may make municipal water hook-up preferable. Also note that treatment costs can vary significantly depending on specific metal and concentration.

The costs of responding to catastrophic events assumed wide areas with groundwater impacted from CO_2 seeps which would require groundwater remediation and providing alternative water supplies to affected residents.

Table 5: Emergency and Remedial Response Events

Event	Consequences	Response Actions
1. Post-injection USDW contamination		
Acidification due to migration of CO_2	Decrease in pH by 1 to 2 units, mobilization of trace and alkali metals, other geochemical changes to groundwater that result in USDW exceeding applicable standards	Hydrogeological study to delineate 3-D extent and nature of impact to USDW. Groundwater extraction with treatment of groundwater or extraction coupled with injection of 'clean' water, if possible. Significant impact to USDW could require supplying municipal water to affected properties.
Toxic metal dissolution and mobilization	Concentrations of toxic metals in USDW greater than applicable standards	Hydrogeological study to delineate 3-D extent and nature of impact to USDW. Groundwater extraction with treatment of groundwater or extraction coupled with injection of 'clean' water, if possible. Significant impact to USDW could require supplying municipal water to affected properties.

[4] Esposito, Ariel M.M. *'Remediation of Possible Leakage from Geologic CO_2 Storage Reservoirs into Groundwater Aquifers.* Stanford University Department of Energy Resources Engineering. June 2010.

[5] Environmental Cost Estimating Tools. In *Federal Remediation Technologies Roundtable.* Retrieved June 9, 2011. From www.frtr.gov.

Table 5 (continued)

Displacement of groundwater with brine due to CO_2 injection	Concentrations of anions/cations in USDW greater than applicable drinking water standards.	Hydrogeological study to delineate 3-D extent and nature of impact to USDW. Groundwater extraction with treatment of groundwater or extraction coupled with injection of 'clean' water, if possible. Significant impact to USDW could require supplying municipal water to affected properties.
<u>2. Post-injection failure scenarios (acute)</u>		
Upward leakage through CO_2 injection well	Groundwater contamination	1) Stop injection, 2) Pull and replace the tubing or the packer, 3) Repair the well by plugging it with cement, 4) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 5) Install chemical sealant barrier to block leaks, and 6) Remediate groundwater (see 1. above).
Upward leakage through deep oil and gas wells	Groundwater contamination	1) Stop injection, 2) Pull and replace the tubing or the packer, 3) Repair the well by plugging it with cement, 4) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 5) Install chemical sealant barrier to block leaks, and 6) Remediate groundwater (see 1. above).
Upward leakage through undocumented, abandoned, or poorly constructed wells	Groundwater contamination	1) Stop injection, 2) Pull and replace the tubing or the packer, 3) Repair the well by plugging it with cement, 4) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 5) Install chemical sealant barrier to block leaks, and 6) Remediate groundwater (see 1. above).
<u>3. Post-injection failure scenarios (chronic)</u>		
Upward leakage through caprock through gradual failure	Groundwater contamination	Stop injection. Remediate groundwater (see 1. above)
Release through existing faults due to effects of increased pressure	Groundwater contamination	Stop injection. Remediate groundwater (see 1. above)
Release through induced faults due to effects of increased pressure	Groundwater contamination	Stop injection. Remediate groundwater (see 1. above)

Table 5 (continued)

Upward leakage through CO_2 injection well	Groundwater contamination	1) Stop injection, 2) Repair the well by plugging it with cement, 3) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 4) Install chemical sealant barrier to block leaks, and 5) Remediate groundwater (see 1. above)
Upward leakage through deep oil and gas wells	Groundwater contamination	1) Stop injection, 2) Pull and replace the tubing or the packer, 3) Repair the well by plugging it with cement, 4) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 5) Install chemical sealant barrier to block leaks, and 6) Remediate groundwater (see 1. above).
Upward leakage through undocumented, abandoned, or poorly constructed deep wells	Groundwater contamination	1) Stop injection, 2) Pull and replace the tubing or the packer, 3) Repair the well by plugging it with cement, 4) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 5) Install chemical sealant barrier to block leaks, and 6) Remediate groundwater (see 1. above).
4. Other		
Catastrophic failure of caprock	Groundwater contamination	Stop injection. Remediate groundwater (see 1. above)
Failure of caprock or well integrity due to seismic event	Groundwater contamination	Stop injection. Remediate groundwater (see 1. above)

Table 5a: Emergency and Remedial Response Estimated Costs

Event	Estimated Cost ($)
1. Post-injection USDW contamination	
Acidification due to migration of CO_2	250,000
Toxic metal dissolution and mobilization	3,500,000
Displacement of groundwater with brine due to CO_2 injection	264,500
2. Post-injection failure scenarios (acute)	
Upward leakage through CO_2 injection well	3,277,500
Upward leakage through deep oil and gas wells	2,070,000
Upward leakage through undocumented, abandoned, or poorly constructed wells	2,070,000
3. Post-injection failure scenarios (chronic)	
Upward leakage through caprock through gradual failure	3,500,000
Release through existing faults due to effects of increased pressure	3,500,000
Release through induced faults due to effects of increased pressure	3,750,000
Upward leakage through CO_2 injection well	805,000
Upward leakage through deep oil and gas wells	402,500
Upward leakage through undocumented, abandoned, or poorly constructed deep wells	402,500
4. Other	
Catastrophic failure of caprock	3,500,000
Failure of caprock/seals or well integrity due to seismic event	3,500,000
Total Emergency and Remedial Response	**30,792,000**

XI. Cost Summary

For the IL-ICCS CO_2 injection site, the total cost for a third party to take corrective actions on wells within the AoR, plug the injection wells, conduct post-injection site care and site closure actions necessary to protect USDWs if ADM were unable to do so is estimated to be $7,795,720 as shown in Table 6. Possible emergency and remedial response actions as necessary to protect USDWs could possibly amount to as much as $3,750,000 for a single event.

Table 6: Total Financial Responsibility Cost by Category

Activity	Total Cost ($)
Corrective action on wells in AoR	231,800
Injection wells & monitoring wells plugging & site reclamation	594,120
Third Party Post-injection site care	6,434,500
Site closure	535,300
Total Financial Responsibility	**7,795,720**

The costs, assuming a 5-year injection period followed by a 10-year PISC period, are shown by category projected over time in Table 7 on the following page

Table 7: Total Financial Responsibility Cost by Category and Year (in 2014 dollars)

Year After Injection Stops	Corrective action on wells in AoR Cost ($)	Injection wells & site reclamation Cost ($)	Post-injection Site Care Cost ($)	Site Closure Cost ($)	Annualized Emergency/ Remedial Response (single event, $)
1	239,800	-	703,800	-	375,000
2	-	-	786,050	-	375,000
3	-	-	408,800	-	375,000
4	-	-	369,600	-	375,000
5	-	-	419,600	-	375,000
6	1,800	-	369,600	-	375,000
7	-	-	369,600	-	375,000
8	-	-	369,600	-	375,000
9	-	-	369,600	-	375,000
10	48,000	594,120	2,019,600	535,300	375,000